NEW ENGLAND'S INSTALLED ELECTRIC GENERATION FORECAST 2013 – 2025

by

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ABSTRACT

The aim of this Master's Project, as identified by our client the C Three Group, LLC, was to forecast installed electric capacity in the ISO New England region through the year 2025 under different scenarios including varying natural gas prices and RPS programs. ISO New England is the Independent System Operator of New England and oversees electric generation and transmission in the New England States.

Our team built a basic supply model and, using linear optimization, we estimated ways for the ISO New England region to expand its supply to meet the growth in forecast demand. We ran our model under different scenarios, including varying natural gas prices and RPS programs. We took into account announced changes to capacity as well as possible scenarios that may affect further changes in the makeup of capacity.

The final results showed continued expansion of natural gas and wind generation, the low-cost leaders, as well as new development of demand response. As we varied the future prices of natural gas, more electricity began to be imported from Canada. We believe that future carbon prices and stricter RPS standards may further ratchet up imports and renewables, in place of natural gas. Finally, our model predicts possible future coal retirements and is doubtful of new nuclear. Our client will potentially use the explanation of our models and written report of our findings in future research and consulting for their business.

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I. INTRODUCTION

i. Background

Our client is the C Three Group, LLC (C Three), based in Atlanta, Georgia. C Three is an energy-consulting firm focused on mergers and acquisitions in energy infrastructure and related industries. C Three's professionals are energy market experts that specialize in providing market due diligences, market information and consulting services related to electric generation, electric transmission, energy pipelines and rates and regulation. Their main clients are utilities, investors, vendors and regulators. The firm provides clients with market data and proprietary reports as well as access to their exclusive industry databases (The C Three Group, 2014).

C Three has provided us with access to and training in their electric generation database. The C Three Electric Generation Database tracks over 23,000 power plants in the United States and Canada. The database includes all fuel types ranging from operational to conceptual. The C Three Electric Generation Database served as the basis for the modeling and forecasting components of the project, with additional information from the Independent System Operator of New England (ISO New England) and the U.S. Energy Information Administration (EIA). Raw data from the C Three's database will remain confidential to us, as requested by the client.

ii. Energy Information Administration Supply Forecast

An important first step in the analysis is to look at existing models relating to the future of the energy mix in the country, to discover prevalent trends and common expectations in order to help guide the creation of a new, ISO-NE-specific model. The EIA's 2012

Annual Energy Outlook (AEO) was our first target. The AEO uses the National Energy Modeling System (NEMS) to build its Reference case and scenarios. The AEO reports varying predictions for U.S. energy consumption and provides a breakdown of the resulting energy mix. The AEO generally predicts a modest increase in the nation's overall consumption in energy to the year 2035 that will be supplied by a shift in the nation's energy mix due to a combination of demographic, technological, economic, and policy factors (U.S. Energy Information Administration, 2012b). From 2010 to 2035, growth in energy consumption is predicted to have an annual rate of 0.3 percent. This forecasted low rate of consumption growth is based upon projected moderate economic and population growth, along with increasing energy efficiency in the U.S. The AEO Reference case predicts total electricity demand will rise by 22% between 2010 and 2025 (U.S. Energy Information Administration, 2012b).

Specifically, the AEO addresses the importance of natural gas and renewables in the future of the entire United States energy system. The report predicts that the share of natural gas in the country's energy mix will rise from 24 percent to 28 percent by the year 2035, renewables increasing from 10 to 15 (U.S. Energy Information Administration, 2012b). "Most of the growth in renewable electricity generation is a result of State RPS requirements, Federal tax credits, and—in the case of biomass—the availability of low-cost feedstocks" (U.S. Energy Information Administration, 2012b). AEO's Reference case assumes that all states will meet their RPS requirements (U.S. Energy Information Administration, 2012b). As these fuel sources are forecast to increase, the share of coal will likely fall from 48 percent to 38 percent over the same time period, according to the

AEO. This takes into account 49 gigawatts (GW) of coal power plant retirements. However, for the AEO Reference case, coal still remains the nation's "dominant fuel" for electricity generation through 2035 (U.S. Energy Information Administration, 2012b).

These parallel phenomena are attributed mainly to predictions of low natural gas prices, existing and new RPS programs, and possible "environmental compliance costs" (U.S. Energy Information Administration, 2012b). That being said, both the Reference and alternative cases assume that there will be no regulation of greenhouse gas (GHG) emissions from existing power plants. Additionally, the AEO Reference case predicts the total installation of nearly 16 GW of new nuclear capacity via both new builds and uprates (page 50) mainly because of $18.5 billion in federal incentives (U.S. Energy Information Administration, 2012b).

iii. The Problem

The electric generation industry in North America is undergoing substantial change. Currently natural gas prices are at inflation-adjusted lows, but historic volatility could return in the future. Nuclear and coal plants are increasingly being retired in North America, largely because the fleet of power plants is aging. Coal, in particular, is currently struggling to compete with new combined cycle natural gas plants and faces the risk of stricter government regulation in the future. Evolving Renewable Portfolio Standard ("RPS") programs are also going to be a factor in how the industry will meet future demand.

As a consulting firm that specializes in information related to electric sector infrastructure, C Three is keenly interested in understanding how these factors will affect the industry going forward. A clearer picture of how various factors may affect future infrastructure development could provide valuable insight to C Three and its clients as they make important business and policy decisions. Specifically, the C Three project managers have tasked us with forecasting the installed electric generation capacity for the Independent System Operator of New England ("ISO-NE") region of the United States.

iv. Electric Markets & ISO – New England

With roughly 8,000 miles of high-voltage transmission lines and covering six states, New England has had a deregulated wholesale electricity market since 1990s. This restructuring allowed five of the six New England states to transform their electric utilities into transmission and distribution companies (New England States Committee on Electricity, Fall 2013). Since then, New England has been an unregulated and competitive wholesale market, which is regulated by ISO New England and Federal Energy Regulatory Commission (FERC) (New England States Committee on Electricity, Fall 2013). Within the wholesale markets, generators are able to sell electricity to utilities and marketers who, in turn, sell to end-users. End users are typically businesses and residential users (ISO New England, 2014b). This move from the vertically integrated model, where decisions are made through central planning, to an unregulated, competitive wholesale structure, shifted the risk from ratepayers to shareholders in terms of investment decisions (New England States Committee on Electricity, Fall 2013). Some other key drivers of the restructuring process, according to the New England State

Committee on Electricity are listed below (New England States Committee on Electricity, Fall 2013):

1. Business decision-making risks have been transferred from consumers to investors.
2. When setting prices, an unregulated market mechanism will be better than regulations
3. Environmental quality, energy efficiency and energy security should be guaranteed and shouldn't be compromised.
4. The lowest cost possibility should always be provided to consumers.

ISO New England is the independent Regional Transmission Organization serving Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island and Maine. ISO New England " helps protect the health of New England's economy and the well-being of its people by ensuring the constant availability of electricity, today and for future generations" (ISO New England, 2014a). In order to meet this obligation, ISO New England has to "oversee the fair administration of New England's wholesale electricity market, ensure the reliable operation of New England's power generation and transmission system and manage comprehensive and regional planning process" (ISO New England, 2014a).

v. Why New England?

ISO-NE is of particular interest because the future of its installed electric generation capacity is uncertain. Also, it could be argued that many of the factors affecting ISO-NE make the region a small-scale representation of the larger forces impacting the rest of the United States' electricity market. Demand for electricity in the region is expected to steadily grow over time along with population (Ehrlich). Despite this projected increase in peak load, the region will be retiring a number of key power plants in the next five to ten years, including the 1.5 GW coal plant Brayton Point (Kuffner, Oct 8 2013), 600 MW nuclear plant Vermont Yankee (U.S. Energy Information Administration, 2013e), and 750 MW coal plant Salem Harbor, among others (Mooney, 2012). These retirements will create a gap between the region's demand and supply of electricity.

Determining how ISO-NE will fill this gap could shed light onto a number of larger energy market questions. Will the region expand its reliance on natural gas, beyond its already relatively high level of more than one third of total capacity (Mooney, 2012)? Will new nuclear plants be permitted and built? Will ISO-NE begin to import more hydroelectricity across the border from Canada (Ailworth, 2013)? If so, will this weaken or bolster the region's push towards renewables? Finally, will these changes require an expansion to ISO-NE's pipeline and transmission infrastructure? These questions must be addressed such that costs are minimized and reliability is maximized.

A number of reports and forecasts exist that address many of the issues raised by C Three at the start of this project. EIA publishes an "Annual Energy Outlook" report, which includes some forecast information (U.S. Energy Information Administration, 2013a). Raw data and forecast information is also available directly from ISO-NE, which we used in conjunction with data from the C Three database.

vi. Objective

Our central goal, as identified by C Three, is to forecast installed electric capacity in ISO New England through the year 2025 under different scenarios such as varying natural gas prices and RPS programs. We took into account announced changes to capacity as well as possible scenarios that may affect further changes in the makeup of capacity (Section II. Methods). The final product includes an explanation of our models and a written report of our findings (Section III. Results). C Three will potentially use these elements of our final product in future research and consulting for their clients.

Through our forecast model, we aimed to address some the following questions:

1. How much installed capacity will renewables, like wind, solar, biomass and domestic hydro provide?
2. What effect will RPS requirements have on the future mix of installed electric generation?
3. Which existing coal and nuclear plants will be retired?
4. What fuel types will dominate the ISO New England region?
5. What will the installed capacity look like in each of the New England states?

II. METHODS & MATERIALS

A. Explanation of Model Structure and Technique

i. Objective Function

To forecast installed electric capacity in ISO New England through 2025, we built an optimization model in Excel using its Solver function. The underlying methodology was to:

1. Calculate the gap of predicted electric capacity supply and projected demand (forecast peak load plus the reserve margin).

2. Minimize the annual costs of filling this gap either by building new power plants or by importing hydro from Canada in each year from 2014 to 2025 under the requirements of each state's Renewable Portfolio Standards (RPS).

The following types of fuel options are included in the model:

Coal
Natural Gas
"Renewables"
Nuclear
Demand Response/Efficiency
Imported Hydro

Note that the model predicts a total number of "Renewables," which we will later break down into four main categories following the percentages of installation from the past five years: biomass, wind, solar, and domestic hydro (see the later section on RPS for more details). Also, imports of hydroelectric (hydro) power from Canada and demand response are considered fuel types in the model. The model chooses a resulting energy mix of each scenario in order to fill the capacity-peak load gap, after meeting the RPS policy constraint, based on each fuel type's levelized costs of electricity (LCOE in

$/MW-year). Since we assume that RPS requirements are implemented regardless of costs, in our model, our first step is to meet this standard for each year. After meeting the RPS, the gap between the year's peak load and installed capacity will be checked. If the peak load is greater than installed capacity, the options with the lowest LCOE to fill the remaining capacity gap will be selected. If the peak load is less than capacity, power plants with the highest LCOE or emissions may be required to retire. We assume that there will be no exports outside of the region. By using this method, we are able to calculate the annual capacity changes in different fuel types of power plants through 2025. By adjusting capacity with these new additions and possible new retirements, the model will be able to forecast the overall installed electric capacity in ISO New England through 2025 under different scenarios.

Specifically, the model can be illustrated with the following equations:

$$\min_{i=1,6} Z = \sum_{i} Capacity\ required\ to\ fill\ in\ the\ gap_i(MW) * LCOE_i$$

Where i: 1,2,3,4,5,6 represents Coal, Natural Gas, Renewables, Nuclear, Demand Response/Efficiency, Imported Hydro

Capacity Gap: except for the year 2013, the capacity gap of other years is based on the capacity change in the previous year

Z: annual cost of filling the capacity gap

Constraints		
1	Capacity Gap	New installations must equal the capacity gap.
2	Renewable Portfolio Standards	The percent of new installations coming from renewables must equal the year's weighted RPS percentage.
3	Natural Gas Pipeline	New natural gas installations cannot exceed 15,000 MW because of estimated limits on the existing pipeline.

4	Canadian Transmission	Imports from Canada cannot exceed 2,600 MW because of limited transmission capacity.
5	New Nuclear	No new nuclear can be built, beyond what has already been announced.
6	Demand Response	New demand response cannot exceed 10% of new installations.
7	Non-negativity	All installations must be greater than or equal to zero.

Note that each input and constraint will be explained in further depth in the later sections of this report.

In this report, we have converted all units of electric generation to MW of installed capacity and of yearly peak load (also referred to as “peak demand”). This was done in order to address the perspective of regional planning, which deals in terms of necessary plant installations required to meet peak demand (i.e. in terms of a minimum amount of total installed and available MW). ISO-NE is interested in maximizing reliability and should plan for the adequate amount of installed capacity necessary to meet peak demand throughout the year, with an adequate reserve margin. In order to convert from units of generation (MWh) to units of installed capacity, we divide by the given assumed capacity factor of each technology. In particular, we are using this conversion method to change states’ RPS programs from a percentage share of generation to the required amount of installed renewable capacity, to the average amount of fuel consumption of various generating sources, and the CO2 emissions rate per MW of fossil fuel plant, among others. Please refer to the individual sections within the report for more details on these conversions.

ii. Base Case (Business as Usual)

As mentioned, the basis for our model inputs was the C Three Group's proprietary North American Power Plant database. C Three's proprietary Electric Generation Database tracks the details of North America's power plants through time. The data is held within Intuit's QuickBase online database software format and is downloadable into Excel. It contains historic installations and retirements starting with the United States' earliest hydroelectric stations through today. These capacity changes include details on fuel source technology, ownership and nameplate capacity, among many other attributes.

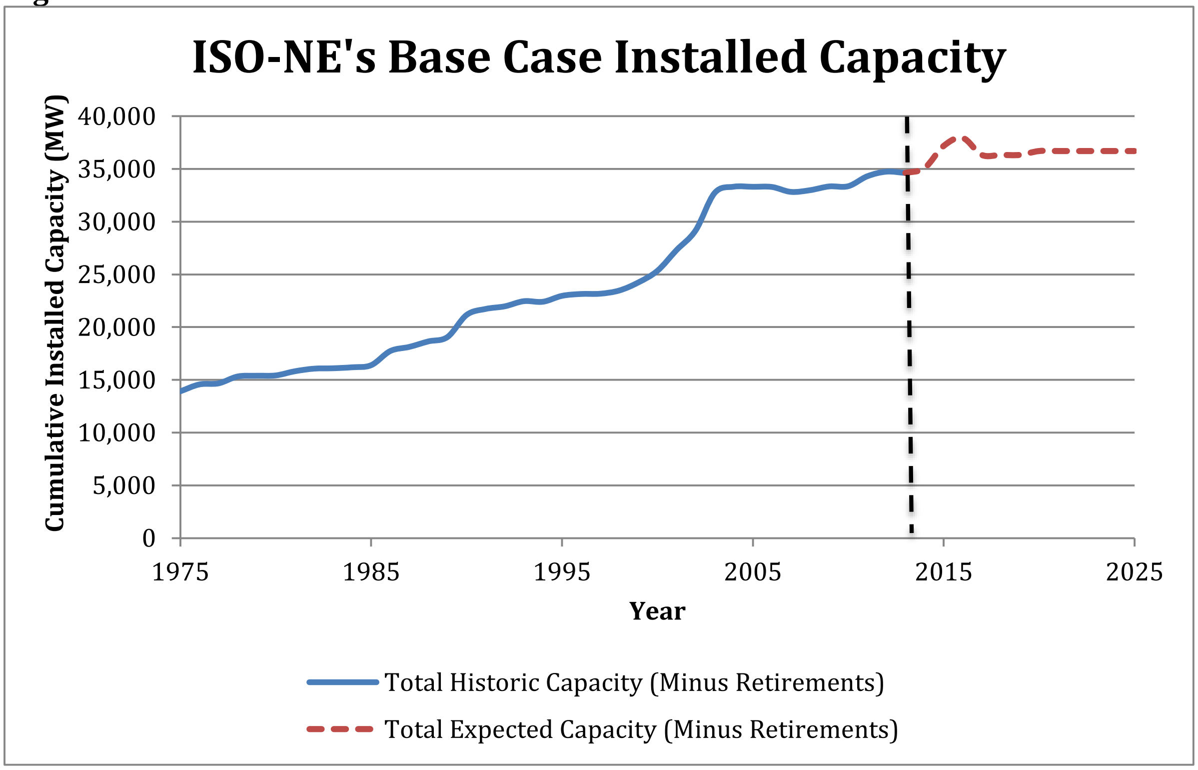
The C Three analysts use proprietary methods to make decisions determining which announced power plant projects are the most/least likely to be carried through. Their expertise and experience with utility companies is essential to making judgments on updating the Database. The value that C Three adds to this data, other than making it accessible and malleable, is its collection and vetting of announced future capacity changes from news articles, press releases and other sources. Using their experience and intimate knowledge of the major players in the power generation industry, C Three's experts rate the probability that an announced addition or retirement will actually happen as planned. Future changes that C Three believes will come to pass are assigned a "real" date in the retirement or new installation field. Those which C Three believes are less likely to happen are given a "dummy" retirement/installation date: 2100 means "early development" and 2150 or 2190 means "on hold, postponed or doubtful," according to C Three's definitions.

For our purposes, the capacity changes that C Three deems ‘likely’ through the year 2025 are used as the “Base Case” scenario in this analysis. We threw out all projects that were “early development” or “on hold” etc. that had dummy dates. It is important to note that since this Base Case scenario relies on C Three’s database, it is inherently dependent on short-term announced plans: power-generating companies do not typically publish their installation/retirement plans beyond about five years into the future. As such, the Base Case will most likely fall short of making installed capacity meet growing peak demand in more than five years, which is the basis of our modeling. Thus, we will call our principle *model* results “Scenario One,” in order to differentiate from the C Three’s Base Case business as usual scenario.

In order to tabulate and visualize the installed capacity changes in the Base Case, we downloaded an extract of C Three’s database, filtering for all power plants in ISO-NE with the following attributes: Plant or Project Name, State or Province, Nameplate Capacity, Primary Energy Source, Initial In Service Year, Retirement Year/Operating License Expiration Year, and Project Status.

The initial raw data produced 1,454 records. Filtering for power plants that are likely to be retired/installed in the future (i.e. those without “dummy” dates) reduced the number to 1,185 power plants. These extend from 9 MW of hydropower installed in 1903 to an expected 36.7 GW of total capacity installed by 2025. In the future, however, ISO-NE’s capacity is predicted to reach a peak by 2016, and then decrease again and plateau as retirements happen and announced plans level out. Figure 1 shows the region’s historic and planned cumulative capacity changes from 1975 to 2025, subtracting retirements from the total installed capacity as they happen. The *expected* future capacity changes are shown in the red dotted line.

Figure 1

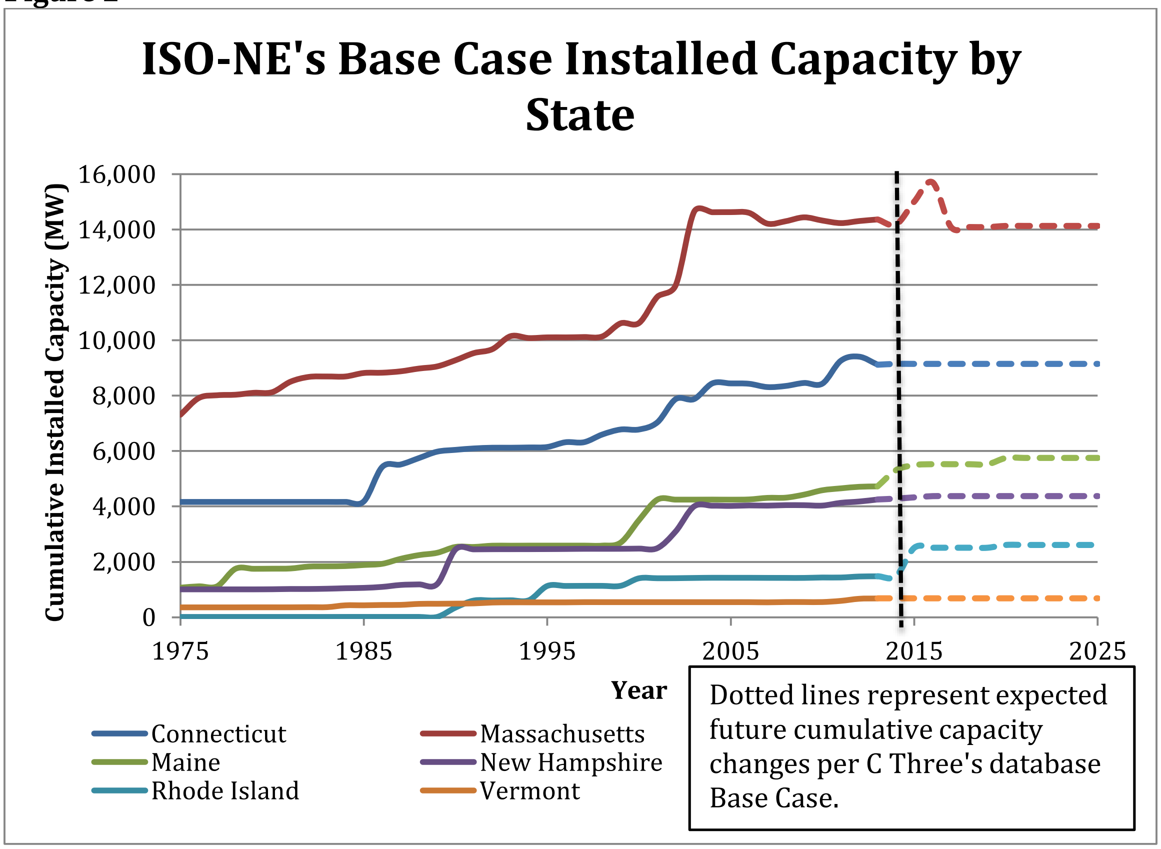


We divided the total cumulative capacity into its respective states as well as the respective generation technologies.

In Figure 2, the states' capacities are broken down. Massachusetts has the highest levels of capacity starting in the late 1950's and sees a large expansion in the 1970's and again in the 1990's. In the Base Case, Massachusetts' capacity is expected to peak in the year 2016 at 15.7GW then see large retirements in following years, settling at around 14GW. The other states show similar trends, though attenuated and at later time periods.

Connecticut has the next highest capacity, with expansions in each decade. Maine and New Hampshire's expansions are closely aligned with each other, with Maine expecting an increase in the future. Rhode Island has a delayed expansion happening in 2016. Vermont's installed capacity has remained low and constant mainly throughout the entire time frame, especially after the 1980s.

Figure 2



In Figure 3, the capacity changes of each technology type are displayed through time. Domestic hydro is the main source of energy in the region until the 1950's. During the 1950's and 1960's, coal installations begin in earnest, eventually replacing hydro as the main source. Other sources also come online in the 1960's including natural gas and "all else" which is composed mainly of oil-based installations. The 1970's see a new expansion of hydro, making it again the biggest technology, along with the first nuclear plants in the region. Nuclear expands in the 1980's, surpassing hydro until natural gas ramps up in the 1990's. Natural gas has represented the largest portion of installed capacity in the region ever since. It is expected to increase in the future, hitting a peak in 2016 at nearly 16.5GW then plateauing. Biomass installation was introduced in the 1980's and wind in the 2000's. The increase in wind power coincides with the decline of coal and "all else" as solar is introduced. All fuel sources generally plateau after 2016 as announced plans diminish. See also Figure 4.

Figure 3

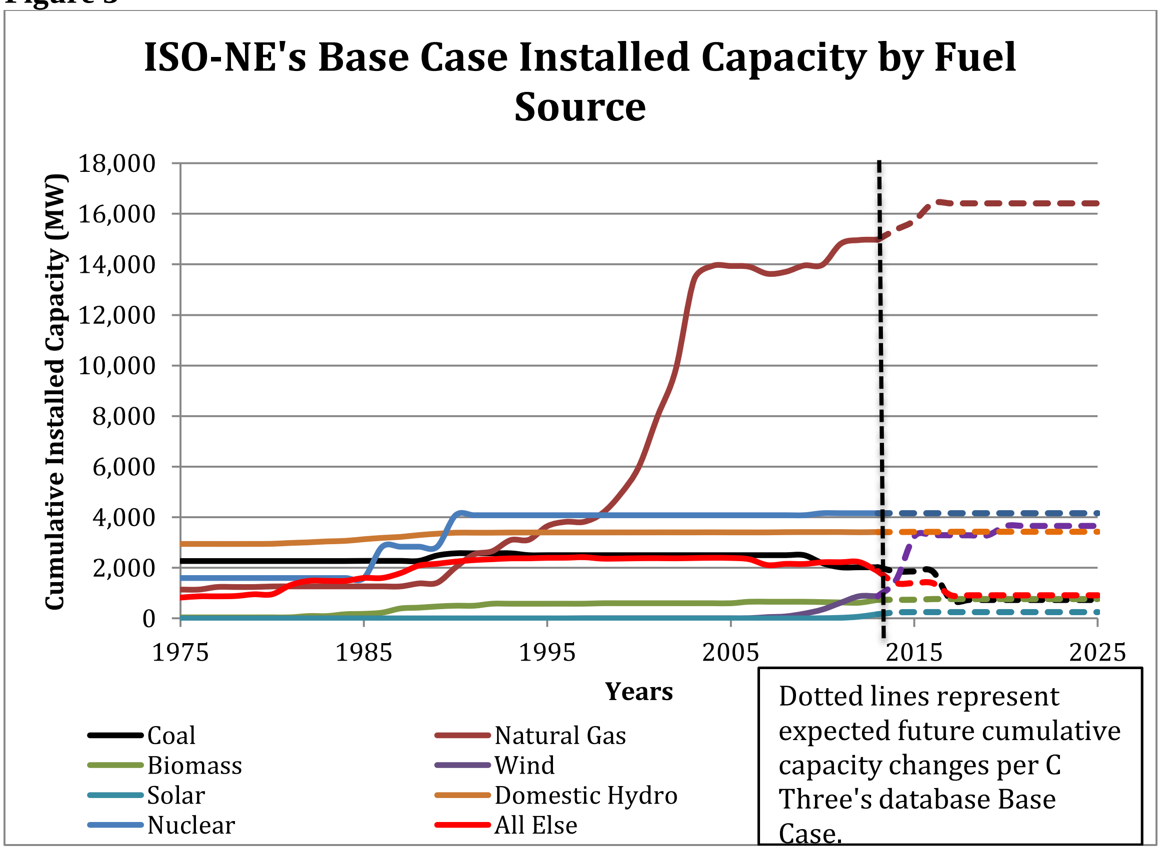
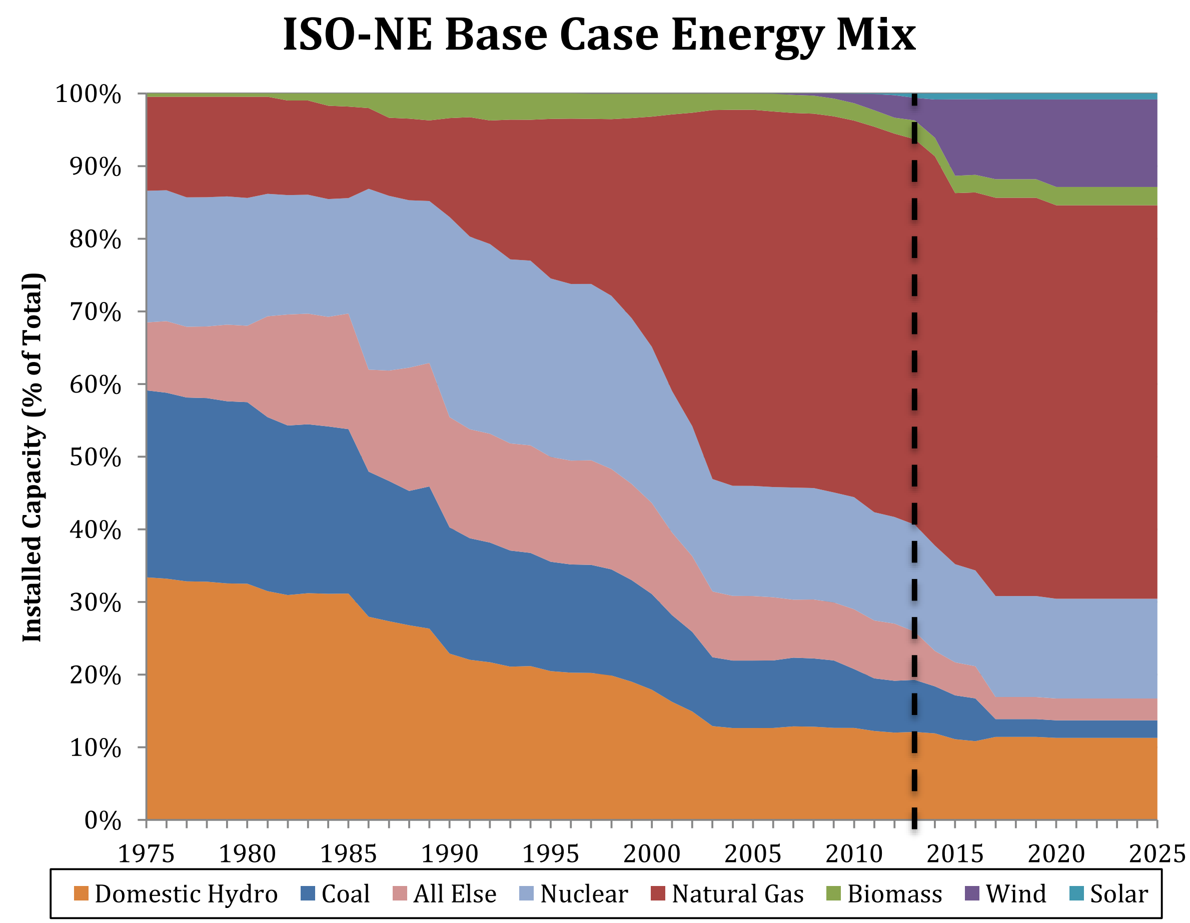


Figure 4



Note that the technologies are ordered chronologically, with ISO-NE's earliest-adopted technologies at the bottom and the latest at the top. Dotted line divides hisotry and projection.

iii. ISO New England Supply Forecast

In order to validate our model output, we compared the supply results from C Three's database to another agency's capacity forecast. The ISO New England CELT Report is the source of assumptions for electric planning. The report is an analysis of capacity, energy, loads and transmission for ISO New England. The report provides projections out to 2022 (ISO - New England, 2013a). In 2022, C Three has projected supply capacity of 36,702 MW. There is a difference of 3,744 MW between the C Three projection and the

ISO NE Summer Peak projection and a difference of 3,387 MW between the C Three projection and the ISO NE Winter Peak projection for the year 2022. Please see Table 1and Table 2 below:

Table 1. ISO New England Summer Peak Capability Projections – Total Capacity (MW)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
32972	32775	33456	33805	33355	32085	32264	32456	32636	32800	32958

Table 2. ISO New England Winter Peak Capability Projections – Total Capacity (MW)

12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
33146	32982	33752	34136	33685	32417	32621	32813	32988	33157	33315

Source: ISO New England

iv. ISO NE Peak Load Projections

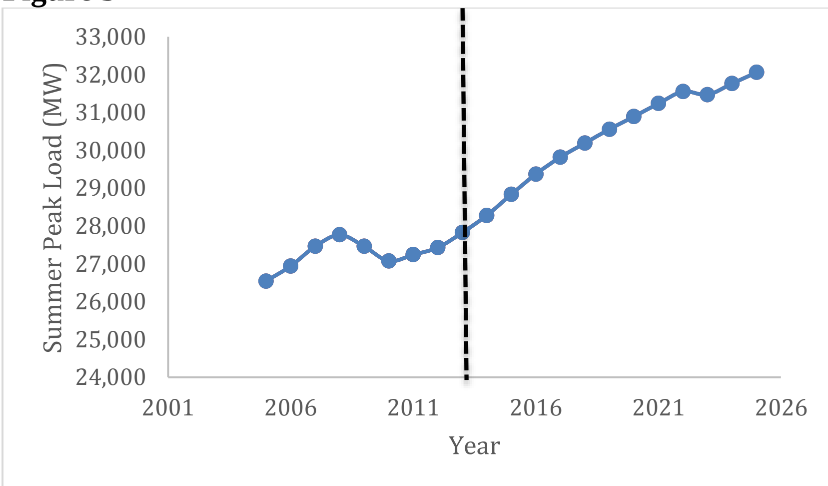
We used the ISO NE Annual Energy & Seasonal Peak forecast as the basis for peak load projections out to 2022. From ISO New England's CELT Report, we also obtained actual summer normal weather peak load for ISO NE (in megawatts [MW]) for the years 2005 – 2012. We also obtained the summer normal weather peak load projection for ISO NE (in megawatts [MW]) for the years 2013-2022. Based on this projection, we project the summer normal weather peak load for 2023 to 2025 using linear regression analysis, which ISO NE did not forecast. According to ISO NE, it appears that summer peak forecasts are fairly stable – 2013 forecasts are pretty much the same as 2012 forecasts. The Annual Energy & Seasonal Peak report concludes that summer peak growth will slow from 1.4% to 0.8% over the next 10 years (Ehrlich). See Table 3 and Figure 5.

Table 3

ISO-NE Forecast Peak Load (GW)												
2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
27.8	28.3	28.8	29.4	29.8	30.2	30.6	30.9	31.2	31.6	31.5	31.8	32.1

Source: ISO New England

Figure 5

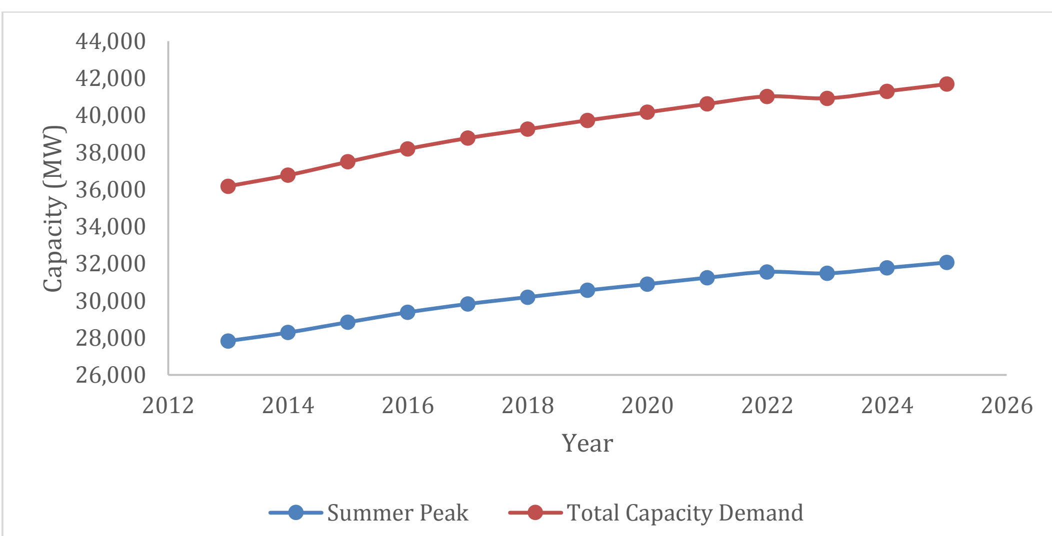


v. Reserve Margin

The operating reserve requirement mandates that ISO New England operators maintain an adequate reserve of electricity supply to enhance the reliability of the bulk power system. Since electricity is generated only on-demand, operators must be able to generate enough electricity in real-time to meet demand while maintaining reserves to be called upon in case of unexpected service problems. Reserves are meant to ramp up only if there is an error with the currently-existing generators, and do so quickly.

According to FERC's market oversight division, in the year 2007, New England's reserve margin was 35.3% (RTO Insider, 2014). In our model, we assume a more conservative level of reserve margin of 30%. As we will discuss further in our conclusions, the choice of a target reserve margin is an important one, which directly impacts the model's output. Certainly, utilities and power producers are constantly dealing with ways to meet growing peak demand (which is usually only ever reached for only single-digit hours during the year), while maintaining safety precautions. Indeed, the excess capacity that is installed as a reserve has a high cost. Although the FERC report cites 35.3% in 2007, assuming a similar reserve into the future may be quite ambitious and ultimately expensive. Other reports we encountered cited lower actual reserves in years after 2007, listed in MW instead of percentages of total installed capacity. Further studies would do well to incorporate a sensitivity analysis surrounding the choice of reserve margin. Nonetheless, taking an assumed 30% reserve margin target into account, our model must make ISO-NE's installed capacity greater than or equal to the region's total peak demand plus 30%, which can be illustrated by Figure 6. Total Peak Demand plus Reserves for New England, 2013-2025.

Figure 6. Total Peak Demand plus Reserves for New England, 2013-2025



vi. Capacity Gap

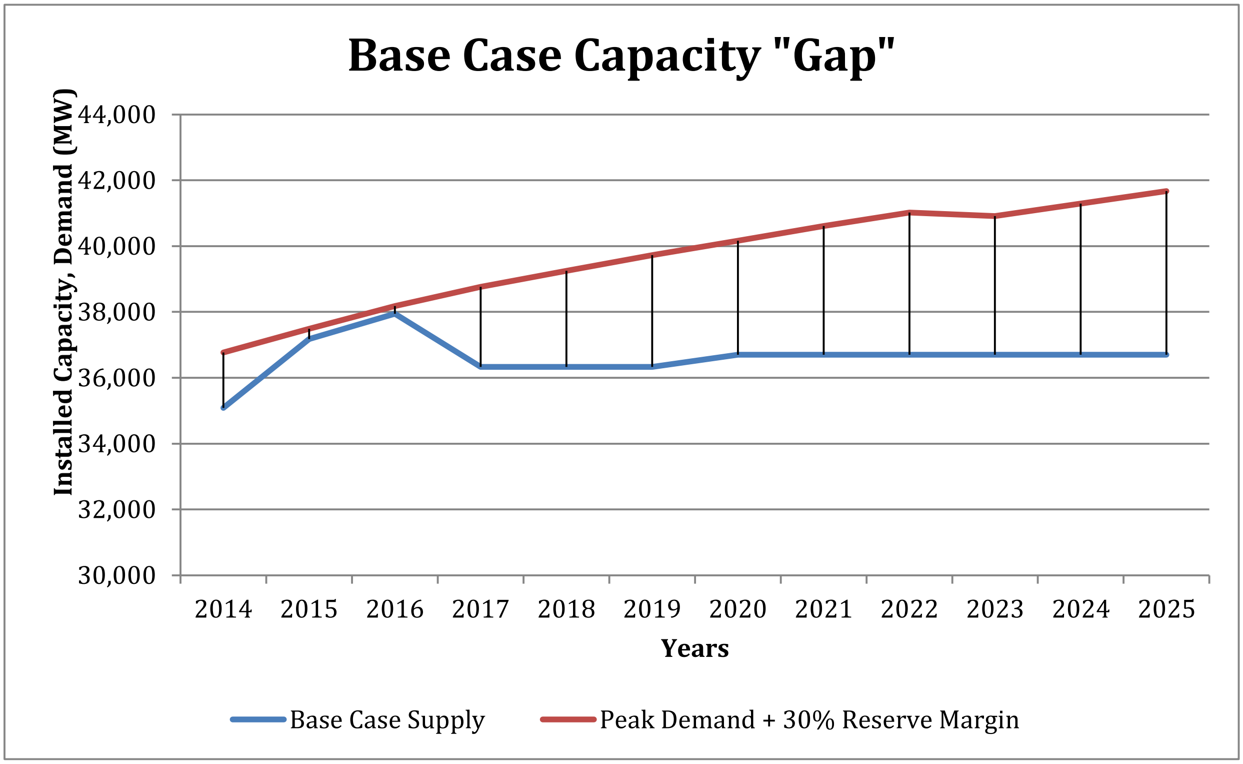
As mentioned, we used C Three's total installed capacity as the Base Case capacity. When we compared these expected capacity changes to ISO-NE's forecast of the region's growth in peak load, it observed a "gap" in capacity in some years, after adding in an assumed reserve margin requirement of 30%. In other words, in the Base Case, the region's peak demand plus the reserve requirement will outstrip its expected installed capacity by this amount in certain years in the absence of new installations. This capacity gap is listed in Table 4 below. The gap is what is fed into the optimization model that will find the lowest-cost way to fill the gap.

Table 4. Capacity Gap Calculations (MW)

	Base Case Supply	Forecast Peak Demand	Peak Demand + 30% Reserve Margin	Capacity "Gap"
2014	35,086.0	28,281.0	36,765.3	1,679.3
2015	37,178.8	28,836.0	37,486.8	308.0
2016	37,944.8	29,372.0	38,183.6	238.8
2017	36,334.8	29,820.0	38,766.0	2,431.2
2018	36,335.7	30,190.0	39,247.0	2,911.3
2019	36,335.7	30,558.0	39,725.4	3,389.7
2020	36,702.7	30,892.0	40,159.6	3,456.9
2021	36,702.7	31,238.0	40,609.4	3,906.7
2022	36,702.7	31,553.0	41,018.9	4,316.2
2023	36,702.7	31,472.4	40,914.2	4,211.5
2024	36,702.7	31,765.6	41,295.3	4,592.6
2025	36,702.7	32,058.8	41,676.4	4,973.7

See Figure 7 for a graph of the yearly capacity gap:

Figure 7



vii. Renewable Portfolio Standards

Each of the six ISO-NE states except for Vermont has an RPS program in place. These laws are all written in terms of *percentage* of total generation that is required to be sourced from renewable energy for each given year up to the end-goal year. It was our task to translate these laws into necessary new installed *capacity* in each year. In order to simplify this complex question, we took the following steps:

We used ISO-NE's "2012 RPS Spreadsheet" that has forecast the future total generation in each state in MWh (ISO - New England, 2012). This spreadsheet then multiplies each state's respective percentage requirements by its total forecast generation to calculate the total required generation from renewables in MWh. We summed the states' MWh requirements and divided by the total ISO-NE forecast generation for each year in order to get a single ISO-NE-wide RPS percentage, summarizing all states' laws. The weighted-average percentages for each year are recorded below in Table 5.

Table 5

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
17%	19%	20%	21%	22%	24%	24%	25%	25%	26%	26%	27%

Notice that the percentages are steadily increasing with time, culminating in 27% by the year 2025.

According to the C Three database, ISO-NE has already installed 1,520 MW of wind, solar, hydro and biogas. We assume that this amount of renewables installation has been sufficient for states to meet their respective RPS up to the start of the model. In order to simplify the RPS requirements in the *future*, we assume that a percent of new installations must be from renewables to stay in compliance with the RPS. Thus, we used the weighted-average RPS percentage of generation (from Table 5) as the basis for our RPS constraint, so that each year, x % of the "gap" must be filled by renewables. We constrained the possible yearly installations of renewables to exactly meet the RPS requirements and not exceed them.

Note that some states have "carve-outs" for specific renewable technologies as defined by different RPS "classes" which must be met regardless of cost. Generally, states list the largest portion of their requirements in Class I renewables, which is the broadest category with the greatest number of qualifying technologies. These include wind, solar, hydro, biogas, tidal/wave, energy storage, and municipal solid waste. If states define subsequent classes, they usually target biogas or hydro specifically. These subsequent classes account for approximately less than a third of the total RPS requirements, on average. Note that the details of these class breakdowns are provided in ISO-NE's "2012 RPS Spreadsheet."

It is logical that utilities will choose to fill the Class I RPS requirements using the lowest-cost technologies. However, we have observed that the majority of new renewable installations in ISO-NE over the past decade have been four main technologies: biogas, hydro, wind and solar. According to C Three's database, from 2003 – 2013, 90.2% of new renewables were from these four technologies. Additionally, in the last five years, these four accounted for nearly 99% of all new renewable installations. Thus, in order to simplify, we assume that in the time frame of the model, all new renewables that will be constructed to meet RPS will come exclusively from these four technologies, in the same percentage breakdown as over the past five years. This implies that the RPS will be met in the following manner:

Table 6

Renewable Type	Historic Percent of Mix
Biogas	14.9%
Wind	68.2%
Solar	10.4%
Hydro	6.5%

We assume that this breakdown will satisfy and perhaps exceed the varying class requirements for all states, given that non-wind is approximately one third of the total, roughly equal to the percent of non-Class I requirements.

To summarize our RPS constraint, in years when the capacity gap is positive and new installations must be built, x% of all new installations must come from renewables, according to Table 5. Of this percentage, the renewables will be broken down using the 5-year trend from Table 6.

B. Model Inputs

Since our model minimizes costs, its results depend on the assumptions that are made about the model inputs. This section discusses the choices we have made regarding inputs, especially focusing on the details of how we estimated each fuel type's LCOE. Our calculations for the fuel consumption and CO2 emissions of fossil fuel plants are especially relevant for our model's final cost estimates and will allow the results to be sensitive to variations in external factors, such as natural prices and potential carbon policy.

i. Capacity Factor

Capacity factor measures the amount of time in a year a power plant runs. It is a measure estimating how much electricity a power plant actually generates versus its maximum generation capacity at full power operation. Power plants with lower fuel costs usually serve as base load supplier and typically have a higher capacity factor of 70% or more. Those power plants with higher fuel costs will only be in operation during peak hours and their operation depends highly on the availability of the fuel source and fuel costs. These plants will have a lower capacity factor.

According to the EIA in 2013, nation-wide capacity factors were as follows (U.S. Energy Information Administration, 2013c):

Assumed Capacity Factors for the US	
Coal	85%
Natural Gas	87%
Biomass	83%
Wind	34%
Solar	25%
Domestic Hydro	52%
Nuclear	90%

ii. CO_2 Emissions and Fuel Consumption

The price of fuel inputs can represent a significant portion of a power plant's variable O&M costs. This cost is a function of fuel prices and fuel consumption. Expectations of future price changes can impact a region's decisions about which type of power plants to install. Similarly, a future carbon tax or CO_2 cap-and-trade policy would raise the variable O&M costs of a coal or natural gas power plant and would also impact decisions about the region's energy mix.

As mentioned, our model deals in units of MW of installed capacity. So part of our task was to determine an average amount of fuel consumed in a year per MW of installed capacity for each fossil fuel type, as well as for tons of CO_2 emitted. This allows us to break down total LCOE into individual components for fuel costs and potential carbon costs for each MW of installed capacity. In order to do this we used historic fuel and carbon data to get a regional average. Note that these data are usually reported in per-generation units (i.e. per MWh). As will be described in more detail below, we converted this to per-installed capacity units (MW) using the assumed average capacity factor for each fuel type.

The historic data we used to calculate the average CO_2 emissions (tons/MW-year) and the average fuel consumption (mmBtu/MW-year) of the power plants in New England is from the 2009 eGRID2012 Version 1.0. (Environmental Protection Agency, 2012) The EPA's eGRID is a database that collects emissions and output data from all of the nation's power-producing plants. The specific calculations are explained as follows based on the data in the worksheet named "PLNT09" of this e-GRID2012 excel file.

CO_2 Emission Rate of Coal Power Plants

First, we filtered for the six states in the ISO New England region: Connecticut, Massachusetts, Maine, New Hampshire, Rhode Island and Vermont in eGrid. Then we filtered the "Plant primary coal/oil/gas/other fossil fuel" category to select only coal power plants. After these two steps, ten coal power plants in New England were left. In order to calculate the average CO_2 emissions of these coal power plants in New England, we used the data in the "Plant capacity factor," "Plant nameplate capacity (MW)" and "Plant annual CO_2 emissions (tons)" categories and used the following equation in Excel to calculate the CO_2 emissions of each of these ten plants:

CO_2 emission rate= Plant annual CO_2 emissions / (Plant capacity factor* Plant nameplate capacity)

We found the average CO_2 emissions of these ten plants to be 8,383.33 tons/MW-year.

CO_2 Emission Rate of Biomass Power Plants

In terms of the CO_2 emissions from biomass power plants, we again used the same methods as for coal power plants. There are 59 biomass power plants in New England based on the eGRID2012 data. The average CO_2 emissions are 4,148.54 tons/MW-year.

CO_2 Emission Rate and Fuel Consumption of Natural Gas Power Plants

To calculate CO_2 emissions and natural gas consumption of natural gas power plants, we used the same methods as above. There are 67 natural gas power plants in New England according to our eGRID2012 data (Environmental Protection Agency, 2012). The average natural gas plant CO_2 emissions are 4,396.99 tons/MW-year.

Since we are also interested in the future of natural gas prices, we calculated New England's natural gas plants' average fuel consumption in per-MW units. For each natural gas plant in New England, we divided its thermal energy input – which is a function of its generation divided by its efficiency – by the heating value of natural gas. Note that we assume the high heating value (HHV) for natural gas to be 52.225 MJ/kg (U.S. Department of Energy, 2012). Generally, this equation is as follows:

Natural gas consumption = ((Generation / Efficiency) / fuel heating value)

Specifically, for these calculations, we extracted the following New England plant data from eGRID"Plant Primary fuel", "Plant capacity factor", "Plant nameplate capacity" and "Plant nominal heat rate (Btu/kWh)."

Similar to our calculations for CO_2 emissions, we then converted from per-MWh units to per-MW units using each plant's capacity factor. Finally, we found the mean value of yearly natural gas consumption per MW of all New England plants to be 74909.43 mmBtu/MW-year or approximately 75,000 tcf/MW-yr. The results from our calculations of CO2 emission rates and fuel consumption for fossil fuel technologies in New England are summarized in Table 7.

Table 7.

Plant Fuel Type	Average	
	CO2 Emissions (tons/MW-year)	**Fuel Consumption** (mmBtu/MW-year)
Coal	8,383.33	
Natural Gas	4,396.99	74909.43
Biomass	4,148.54	

iii. Natural Gas Price Projection

In terms of the natural gas price, the prices in New England are usually higher than those on the national level (Cunningham, 2014). Therefore, projected New England natural gas prices are based upon the national natural gas prices projection through 2025. First, we found the natural gas prices projected through 2025 on the national level (U.S. Energy Information Administration, 2013b). Then we found the natural gas prices of each of the six states in New England from 1997 to 2012 (U.S. Energy Information Administration, 2014). Based upon this data, we calculated the annual average natural gas prices of the six states from 1997 to 2012. Next, we compared the historical data of both the national and the New England's natural gas prices from 1997 to 2012, which is shown in Figure 8.

It can be observed that the New England natural gas prices are usually slightly higher than those in the US. Based on this historical data, we calculated the natural gas price in New England is 7.712% higher than that on the national level. We assume that this average rate will continue till 2025. Based on this rate and the natural gas prices and the national projection of EIA, we obtained the natural gas projection for New England through 2025 (See Figure 9). In the model, we use natural gas prices in the unit of \$/mmBtu. The natural gas price units were converted from \$/thousand cubic feet to \$/mmBtu. Based on the density of methane, 1 thousand cubic feet of natural gas equals 1.006 mmBtu, so the final natural price projection of New England from 2013 to 2025 is shown in Figure 10. Natural Gas Prices in New England, 2013-2025.

Figure 8. Comparison of Natural Gas Prices between US and New England, 1997-2012

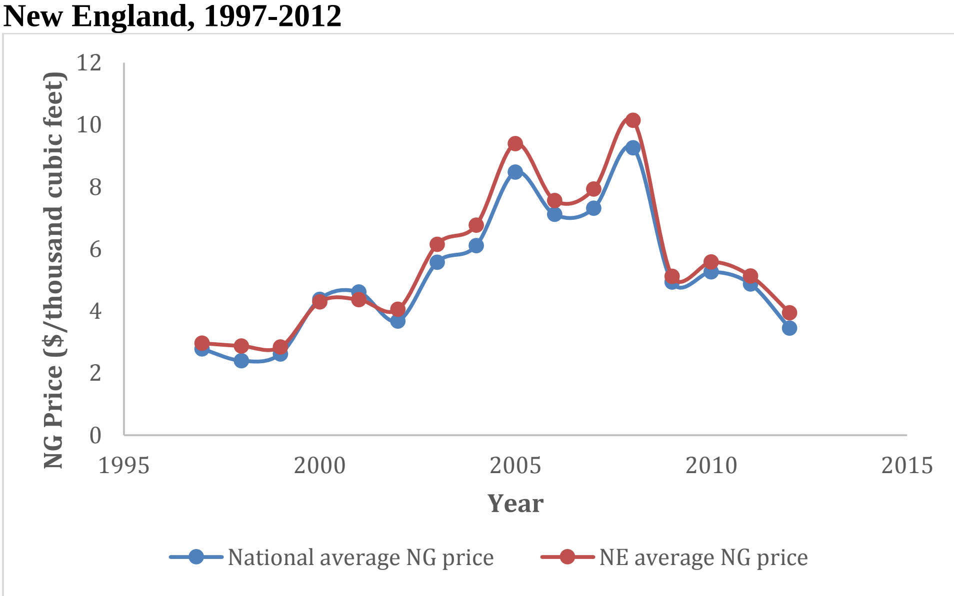


Figure 9. Comparison of Natural Gas Prices between US and New England, 1997-2025

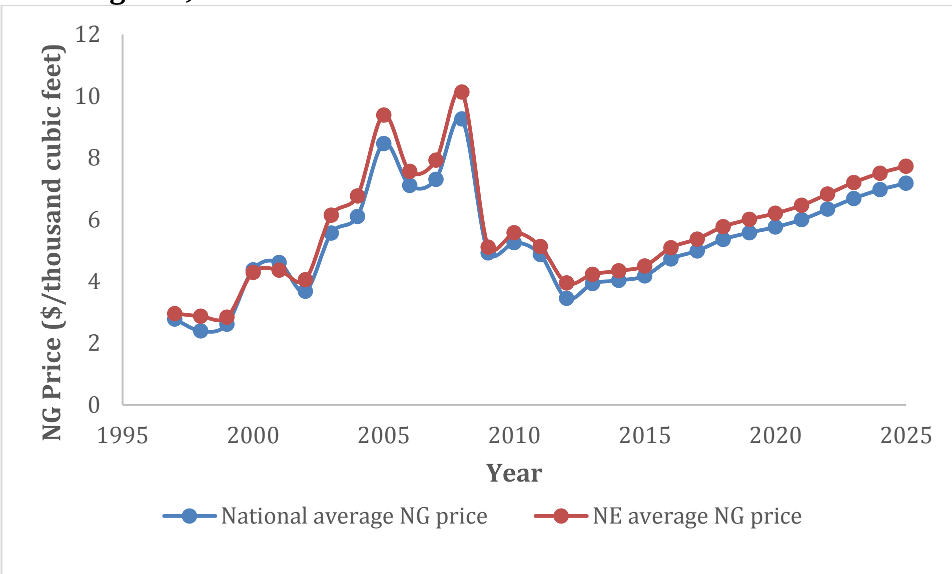
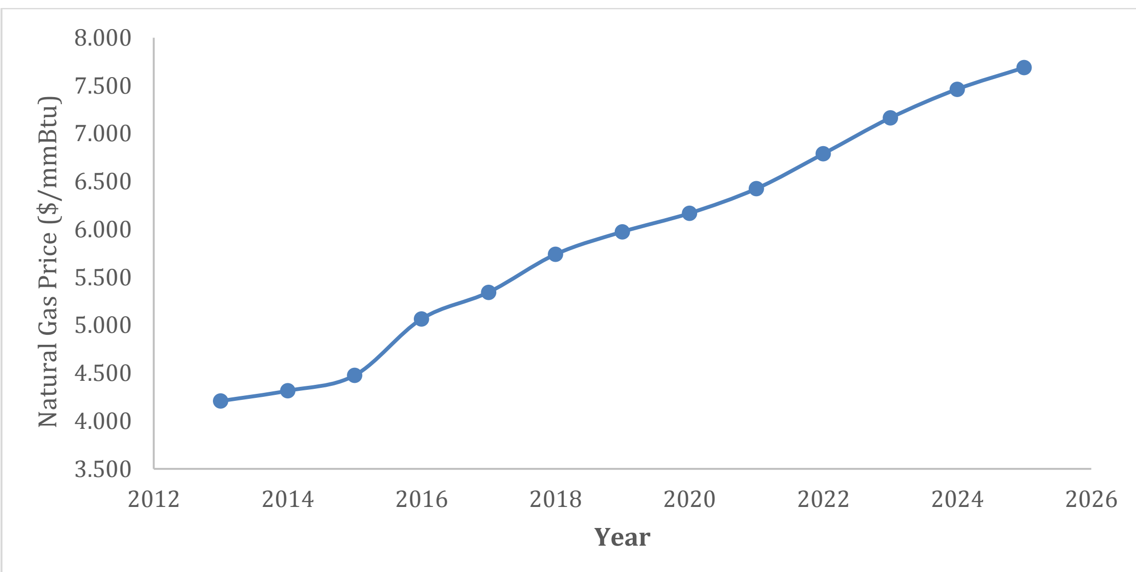


Figure 10. Natural Gas Prices in New England, 2013-2025



For the rest of our cost coefficients, we used a breakdown provided by the EIA on average capital, fixed O&M and variable O&M costs. For natural gas, we subtracted fuel costs from the EIA variable O&M estimate and added each year's fuel price projection separately. Note that the EIA LCOE values are initially given in terms of $/MWh. We converted these to $/MW by dividing by the assumed capacity factor. See Table 8 for a summary of LCOE coefficients for 2014:

Table 8

	Capacity factor	Overnight Capital Expenditures	Fixed O&M	Variable OM (including fuel)	Fuel Prices	Total LCOE ($/MWh)	$/MW-yr
Demand Response/Efficiency	1			33,959.5	-	33,959.5	$33,959.50
Wind	0.34	70.3	13.1	0	-	83.4	$248,398.60
Solar	0.25	130.4	9.9	0	-	140.3	$307,257.00
Domestic Hydro	0.52	78.1	4.1	0	-	82.2	$374,437.40
Natural Gas	0.87	17.4	2	2.5	42.4	64.4	$490,805.30
Biomass	0.83	53.2	14.3	42.3	-	109.8	$798,333.80
Nuclear	0.9	83.4	11.6	12.3	-	107.3	$845,953.20
Imported Hydro	1			100.1	-	100.1	$876,876.00
Coal	0.85	84.4	6.8	29.2	-	120.4	$896,498.40

iv. Hydropower Transmission Line

In order to meet state objectives and requirements to reduce carbon emissions, hydroelectric power, as one of the most promising low-carbon resource, is considered to be one of the best options among the six New England states. New England officials are currently analyzing the potential to increase hydro imports from Canada. Currently, there are four major active transmission grid connections between eastern Canada and New England (New England States Committee on Electricity, Fall 2013).

1. Highgate:
   a. It is a 200MW direct current tie built in 1985. It is one of the connections with Quebec and built to provide power to Vermont during a long Vermont Yankee outage.

2. Quebec/PhaseII

    a. New England's major interconnection with Quebec. It was built in two phases. In phase I, its electrical rating was 690 MW and was 2000 MW in phase II. The plant was designed to have phase I and phase II operate at the same time.

    b. The HQ phase II DC tie still has an equipment rating of 2000 MW, but ISO New England assumes the transfer capability to be 1400 MW for capacity and reliability calculation purposes (ISO - New England, 2013c).

3. MEPCO

    a. Two interconnections with New Brunswick. Their total transfer capability is 1000 MW. MEPCO line, the first tie line, built in 1969, is rated at 700 MW.

4. NRI

    a. Northeast Reliability Interconnect, is the second New Brunswick tie and is rated at 300 MW of interconnection capability.

Recently, new transmission lines between eastern Canada and New England have been proposed in order to increase power flows between the two regions. Several proposed projects are described below. (New England States Committee on Electricity, Fall 2013).

1. The Green Line by New England Independent Transmission Company is a proposal for 1000 MW to 12 MW HVDC system to connect wind energy in Arrostook County, Maine to electric power markets located in the southern region of New England.

2. Northern Pass by Hydro-Quebec and Northeast Utilities: Northern Pass is proposed to be a 1,200 MW HVDC line connecting the Des Canton Substation to a converter terminal in Franklin, New Hampshire.
3. The Northeast Energy Link by National Grid and Bangor Hydro
   It would be located within New England and is proposed to be an approximately 230 mile HVDC transmission line running from Maine to Massachusetts with up to 1,100 MW of capacity.

We chose to impose a constraint on the model given the details of the international grid connections. In any given year, the amount of imported hydro power cannot exceed a maximum transmission level of 2,600 MW because of the existing grid connection constraints. Note that in our Scenario One model, we assume that none of the proposed new transmission lines will get built between Quebec and New England. We address this point further in our discussion of scenarios. The summary of these details are provided in Table 9:

Table 9

Canadian Transmission Interconnections	
Name	Maximum Capacity (MW)
Highgate	200
Hydro-Quebec Phase II	1,400
MEPCO	700
NRI	300
Total	**2,600**

v. Natural Gas Pipeline

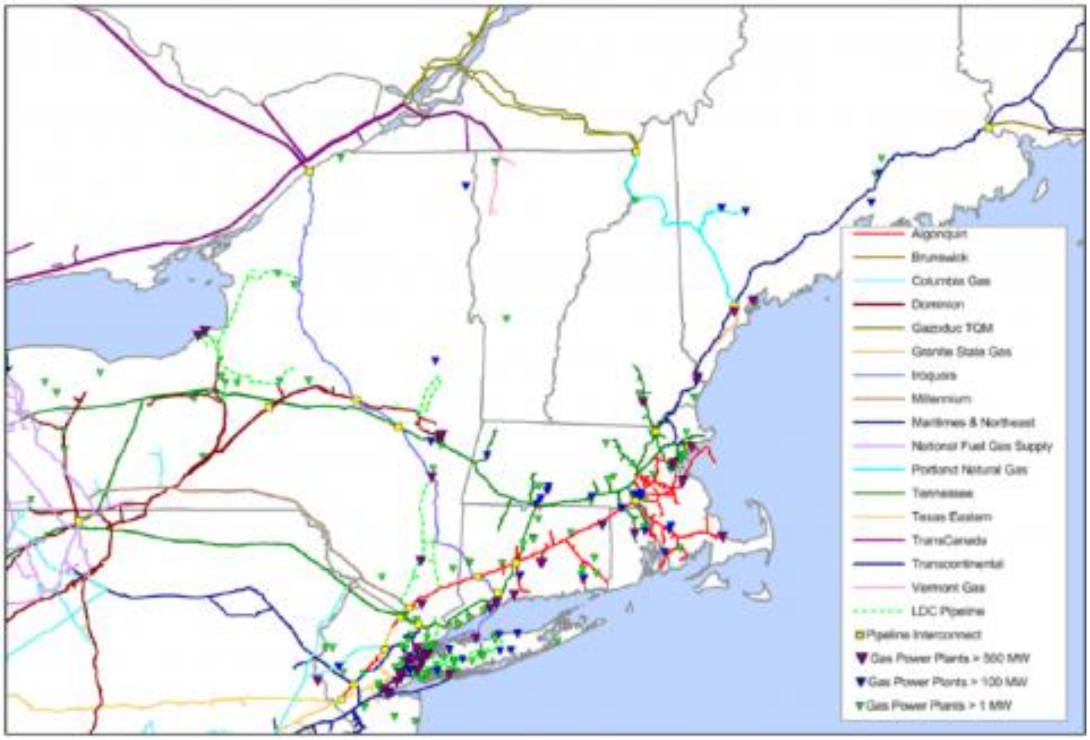
Natural gas, which makes up one-third of the US power supply, rose dramatically in price during 2013. Prices increased evenly across the whole country, except for New England.

One of the main reasons is the shortage of natural gas pipeline capacity in New England, which leads to severe price spikes during cold days in the winter (Cunningham, 2014). During spring, summer and fall, generation is relatively stable. But in the winter of 2013, when space heating needs and gas needs for power generation increase dramatically, the existing natural gas pipeline capacity is very constrained.   Residential heating needs are given priority over power generation in terms of existing natural gas pipeline supply.

The Tennessee Gas Pipeline (TGP), the Algonquin Gas Transmission (AGT) line, and the Iroquois Gas Transmission (IGT) line from the west through New York State, and the Maritimes & Northeast Pipeline (MNP) and the Portland Natural Gas Transmission (PNGT) from the east and north through New Brunswick and Quebec, respectively provide virtually all of New England's gas (Carr, 2014). Additional new pipeline projects are in various stages of development. However the future completion of these projects is a matter of subjective speculation and probable doubt because of the high financial and political costs associated with general NIMBYism (Suzenski, 2014).

Therefore, in our Scenario One model, we assume that none of the proposed new pipelines will be built. Our constraint on the natural gas pipeline is such that new natural gas plants cannot exceed 40% of current installed capacity, which is approximately 15GW. We discuss this further in our scenario analysis, however.

Figure 11. This map above shows New England's pipelines and its gas-fired power plants (ISO - New England, 2013b).



Some of the planned interconnection enhancement projects are listed as follows by the Northeast Gas Association (NGA). The following table is taken directly from the NGA's 2014 report on current pipeline projects (Northeast Gas Association, 2014):

Table 10

Project	Company	Est. In-service
Rose Lake	Tennessee Gas Pipeline	Nov. 2014
Wright Interconnect Project(WIP)	Iroquois Gas Transmission	2015
Niagara Expansion	Tennessee Gas Pipeline	Nov. 2015
Connecticut Expansion	Tennessee Gas Pipeline	Nov. 2016

Continent to Coast(C2C) Expansion	PNGTS	Nov. 2016
South-to-North("SoNo") Project	Iroquois Gas Transmission	Nov. 2016
Northeast Expansion	Tennessee Gas Pipeline	2018
Eastern Long Island (ELI) Project	Iroquois Gas Transmission	2017

vi. Demand Response

Demand response is a term used for programs that can call upon customers to temporarily reduce their load. Customers who participate in these programs agree to a maximum level of curtailment load if called upon. In turn, they receive capacity payments for participation, as well as curtailment payments that are products of time of event and current price of electricity. We treated demand response as an additional generation resource, summing its capacity to supply as opposed to subtracting it from demand. It is assumed that demand response capacity additions are permanent and that customers participating in such programs either sign long contracts or are easily replaced. The costs used were estimated in terms of a total $/MW price point, using historical market trading data from the May 2010 "Analysis of Load Payments and Expenditures under Different Demand Response Compensation Schemes" report in PJM Interconnection (PJM Interconnection, May 2010).

Although some experts argue that there is no theoretical limit to the amount of demand response entering into a region's energy mix (Kirby, 2014), we opted for finding a practical yearly maximum. The constraint that was chosen was based on a ruling in PJM

(ER14-504) that limits reliance on demand response to 10% (RTO Insider, 2014). Thus, the model constrains demand response to a maximum of 10% of the new installations in a given year.

III. RESULTS

i. Scenario One Model Results

The "Scenario One" model was run one year at a time, with the size of the capacity gap in one year changing depending on the installations in the previous year's model results. The first year's gap was the largest at 1,679MW. Subsequently, the gap was again positive six of the eleven years, averaging 406MW per year as peak demand steadily grew and the business-as-usual retirements began to occur. In the remaining five of eleven years, the gap was negative, meaning there was a surplus of supply (i.e. beyond the 30% reserve margin). We looked at how the cumulative capacity changes if there are no non-planned retirements versus if there are new retirements (in particular, coal plants) in years when capacity exceeds peak load.

In the first place, when we make no new retirements in the years when capacity exceeds peak load, the final results are as follows:

Table 11

Scenario One Model: Resulting ISO-NE Installed Capacity (MW)							
	Coal	**Natural Gas**	**Renewables**	**Nuclear**	**Demand Response/ Efficiency**	**Imported Hydro**	**All Else**
2014	1,856.9	16,594.6	6,193.4	4,160.9	167.9	0.0	1,397.9
2015	1,856.9	16,944.6	7,936.2	4,160.9	167.9	0.0	1,397.9
2016	1,856.9	17,634.6	8,012.2	4,160.9	167.9	0.0	1,397.9
2017	732.3	17,634.6	8,013.1	4,160.9	167.9	0.0	911.6

2018	732.3	17,897.9	8,100.8	4,160.9	206.8	0.0	911.6
2019	732.3	18,215.6	8,213.6	4,160.9	254.7	0.0	911.6
2020	732.3	18,501.1	8,685.9	4,160.9	298.1	0.0	911.6
2021	732.3	18,794.4	8,797.4	4,160.9	343.1	0.0	911.6
2022	732.3	19,059.2	8,901.2	4,160.9	384.0	0.0	911.6
2023	732.3	19,059.2	8,901.2	4,160.9	384.0	0.0	911.6
2024	732.3	19,235.0	8,974.1	4,160.9	411.7	0.0	911.6
2025	732.3	19,235.0	8,974.1	4,160.9	411.7	0.0	911.6

The model added 2,818MW of new natural gas, 887 MW of renewables and 412MW of demand response. As mentioned in a previous section, the RPS constraint was forced to be binding, serving both as a minimum and maximum requirement. Using the historic break-down of the main four renewables, we would expect the total 887 MW of new renewables to come from the following sources:

Table 12

Expected Percentage Installations of Renewables				
	Biomass	Wind	Solar	Domestic Hydro
2014	923.6	4,220.8	646.4	402.6
2015	1,183.5	5,408.5	828.3	515.9
2016	1,194.8	5,460.3	836.2	520.8
2017	1,195.0	5,460.9	836.3	520.9
2018	1,208.0	5,520.7	845.4	526.6
2019	1,224.9	5,597.6	857.2	533.9
2020	1,295.3	5,919.5	906.5	564.6
2021	1,311.9	5,995.5	918.2	571.9
2022	1,327.4	6,066.1	929.0	578.6
2023	1,327.4	6,066.1	929.0	578.6
2024	1,338.3	6,115.9	936.6	583.4
2025	1,338.3	6,115.9	936.6	583.4

The demand response constraint was binding as well. Demand response was found to have the lowest LCOE cost coefficient, so the model chose to maximize its installations up to the allowable limit of 10%. Other constraints were not binding. Although natural gas was installed in every year in which there was a positive capacity gap, the total new installations fell short of the 15,000MW pipeline constraint. The constraint on imported hydro was not binding because the model did not choose to import any amount. Finally, the model did not allow for any new nuclear to be built because of doubts as to the future of new nuclear beyond what has already been announced. This was based on an EIA study that said, “There is uncertainty about the ability of the nuclear industry to ramp up quickly” (U.S. Energy Information Administration, 2012a). The following two figures and table show the resulting changes in ISO-NE’s energy mix given these inputs:

Figure 12

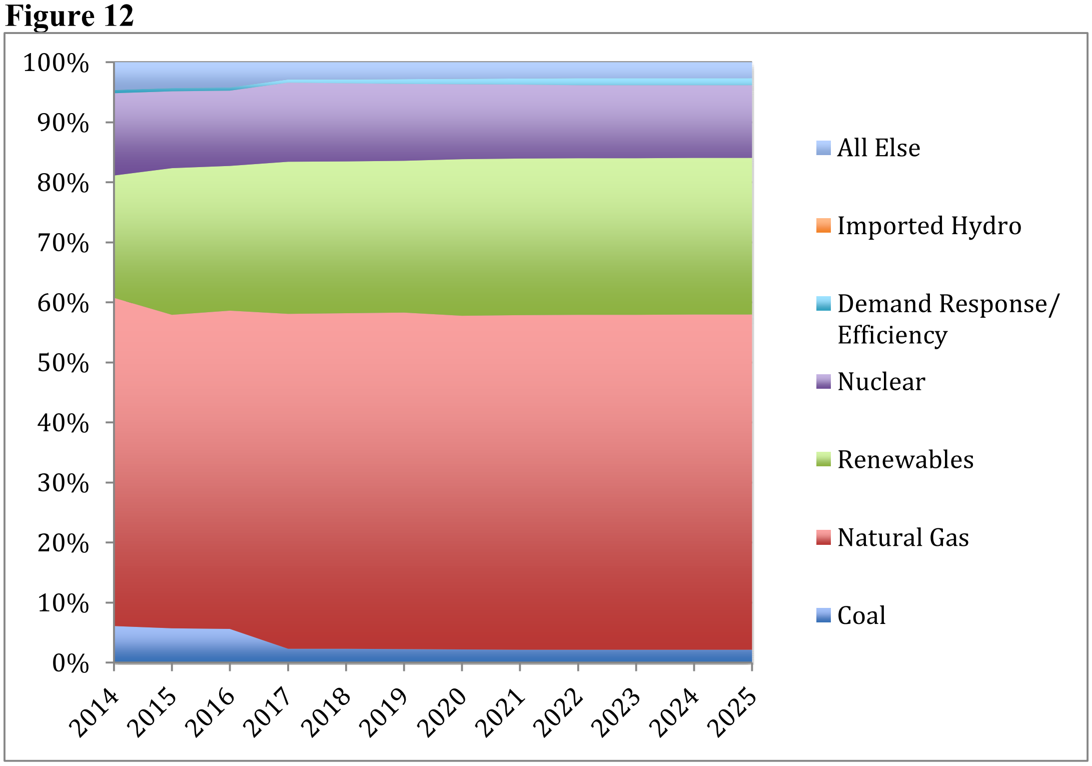


Figure 13

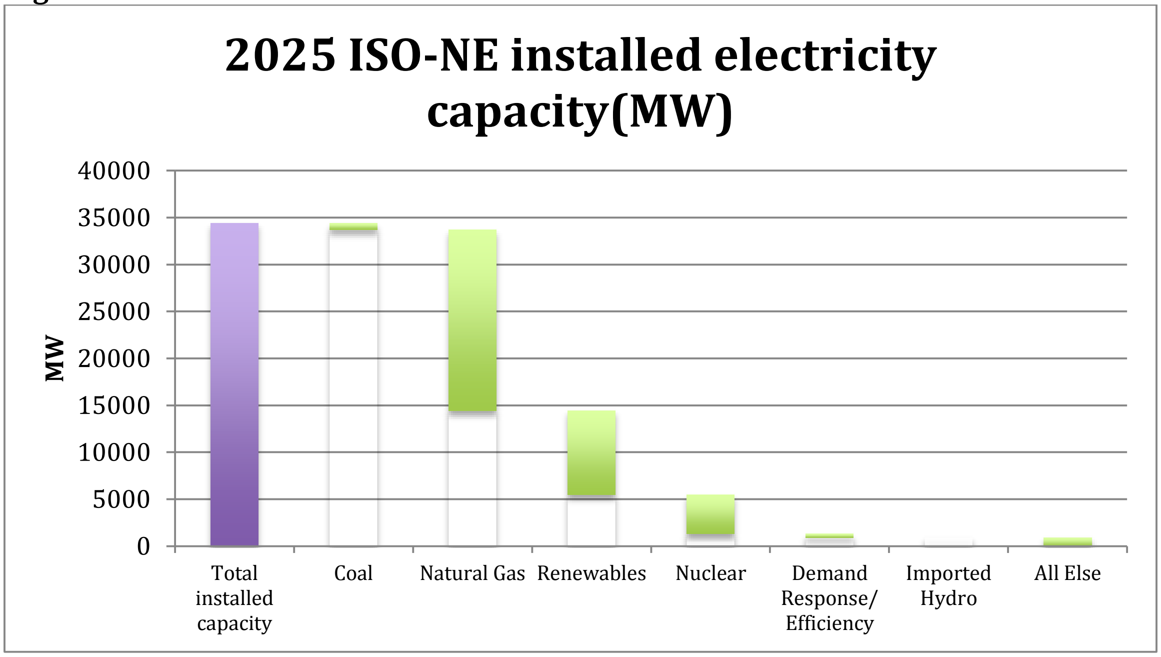


Table 13

Base Case Model: Resulting ISO-NE Installed Capacity, 2025 (% of Energy Mix)						
Coal	**Natural Gas**	**Renewables**	**Nuclear**	**Demand Response/ Efficiency**	**Imported Hydro**	**All Else**
2.1%	55.9%	26.0%	12.1%	1.2%	0.0%	2.6%

The alternative method to running the Scenario One model is to *retire* plants in years when the capacity gap is negative, i.e. when there is surplus capacity. We believe that, in years when capacity exceeds peak load, it is *plausible* that the region makes the decision to retire its worst plants however it decides to qualify them as such. These criteria could include plants that have the highest emissions rates, lowest efficiencies or highest LCOE. Another possibility is to retire *some* of the surplus capacity and *export* the remainder to outside the region. This option appears to be more realistic, considering that generating entities would normally be reluctant to retire all of the excess capacity if their capital costs have already been covered and if revenue can be made from keeping them in operation. Under this retirement method, the Scenario One model results in three years when the capacity gap is negative for a total of 1,545 MW of surplus capacity that must either be retired or exported. If we assume that the plants with the highest CO2 emissions get retired first, all the new retirements will come from coal. This implies that by 2025 a total of 732 MW of coal is retired beyond what is planned in the C Three database. These additional unplanned retirements equal the *entirety* of ISO-NE's installed capacity of coal (Suzenski, 2014). This may not be too far from reality. According to David Suzenski, we are likely to "see the end of all coal in New England within 10 years." For means of comparison, we assume that the remaining 812 MW of excess capacity will be exported. The base case model results under the retirement method show the following new installations and retirements/exports for each given year (retirements show as negative numbers):

Table 14

New Installed Capacity (MW)						
	Coal	**Natural Gas**	**Renewables**	**Nuclear**	**Demand Response/ Efficiency**	**Imported Hydro**
2014		537.4	293.5		848.4	
2015	-732.3					-639.0
2016						-69.2
2017		831.2	466.6		894.6	
2018			107.1		373.0	
2019			112.8		365.6	
2020			16.3		50.9	
2021			111.5		338.3	
2022			103.7		305.8	
2023						-104.7
2024			100.6		280.5	
2025			102.6		278.5	

We find that the decision to retire or export in years when capacity happens to exceed peak load actually leads to greater need for new installations in the future. In fact, under the retirement method, the model installs a total of 6,518 MW through 2025, approximately 2,400 MW more than when no retirements are made. In essence, new retirements now compound the pressure to install new capacity in later years when the gap is positive. Thus, the region is making a tradeoff between the benefits it gains from retiring (such as reduced emissions or greater efficiencies) with the costs of installing new capacity.

This could demonstrate that the assumed reserve margin of 30% in ISO-NE is set too high and that the region is installing new capacity too aggressively in years when there is a positive gap between current capacity and peak load.

ii. Scenario Analysis

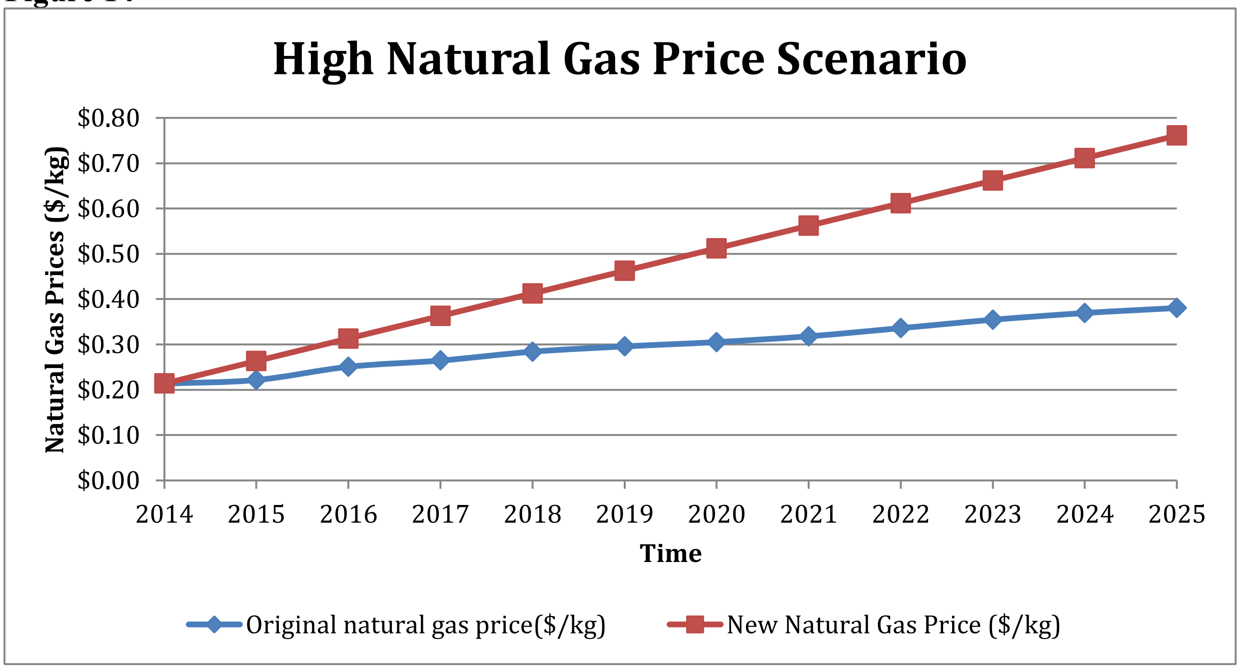
There is a substantial amount of uncertainty in many of the variables influencing ISO-NE's energy mix, as reflected in the inputs of the model. Thus, we decided to run scenario analyses to see how the final model output changes as these variables do. Specifically, we chose to analyze the effects of higher natural gas prices, higher carbon prices and stricter RPS requirements.

The first scenario has natural gas prices 100% higher in year 2025 than in the base case, or $0.76/kg. We assumed a price projection that followed a linear trend. The yearly natural gas prices were the following, all else the same:

Table 15

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Original natural gas price($/kg)	$0.21	$0.22	$0.25	$0.26	$0.28	$0.30	$0.31	$0.32	$0.34	$0.35	$0.37	$0.38
New Natural Gas Price ($/kg)	$0.21	$0.26	$0.31	$0.36	$0.41	$0.46	$0.51	$0.56	$0.61	$0.66	$0.71	$0.76

Figure 14

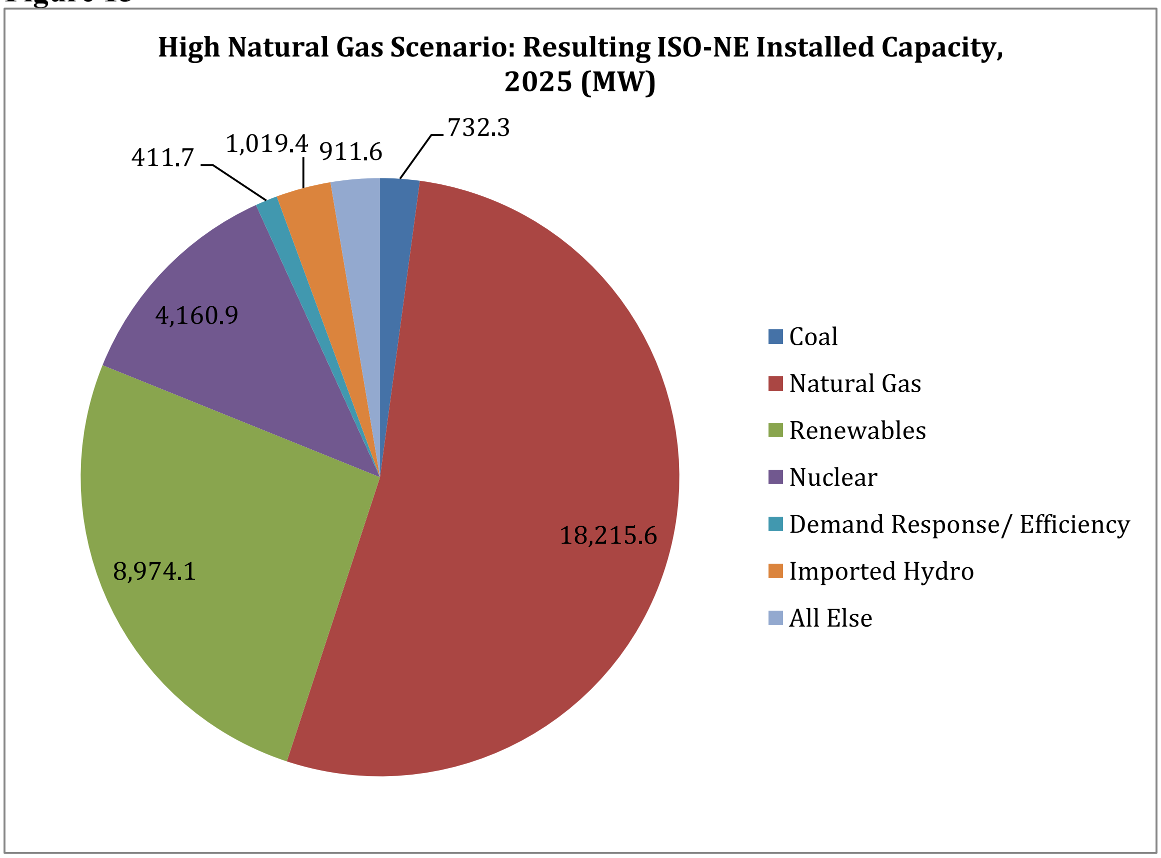


This 100% increase in natural gas prices results in a break-even point in year 2020, in which the model becomes indifferent between natural gas installations and imported hydro, the next lowest-cost option. Thus, the total amount of installed natural gas is decreased and the region begins to rely more on imported Canadian energy. Note that the import constraint is still not broken. The results are the following:

Table 16

High Natural Gas Scenario: Resulting ISO-NE Installed Capacity, 2025						
Coal	**Natural Gas**	**Renewables**	**Nuclear**	**Demand Response/ Efficiency**	**Imported Hydro**	**All Else**
732.3	18,215.6	8,974.0	4,160.9	411.7	1,019.4	911.6

Figure 15



Higher RGGI carbon prices impact the final LCOE cost coefficients of fuel technologies that emit CO2, as discussed, which include coal, natural gas and biomass. Stricter RPS requirements will potentially reduce the amount of natural gas or imported hydro and raise total costs.

iii. Other Scenarios

In future studies, we would recommend analyzing scenarios in which there is higher-than-projected and lower-than-projected peak demand. We would also suggest using three sub-cases under both of these scenarios to analyze changes based on high natural gas prices, higher carbon prices and stricter RPS standards, as was done in the base case scenario.

IV. DISCUSSION

Through our forecast model, we aimed to address some the following questions:

- How much installed capacity will renewables, like wind and solar, provide?
- What effect will RPS requirements have on the future installed capacity mix?
- What fuel types will dominate the ISO New England region?
- What will the installed base look in each of the New England states?

As we began to build our regional model, it became apparent that our choice of assumptions for inputs and constraints has a large impact on the model's results. Especially important are the cost coefficients chosen for each decision variable technology, as well as the amount of renewables required each year to meet all states' RPS and the ever-changing maximum constraint to the region's natural gas pipeline. We hope that we have been able to provide the C Three team with sufficient background research into each of these points of uncertainty that they will be able to better understand our choices and make more informed decisions about their own future modeling.

According to the model, most of the gap between installed capacity and peak load will be filled with natural gas, wind and demand response, which have relatively lower LCOE compared to the other fuel types. Demand response could be regarded as a special source of capacity. Instead of increasing capacity installations on the supply side, it will redistribute electricity on the demand side. In our model, we actually set a maximum limit on the demand response capacity, since it is not supposed to be utilized to fill the capacity gap even if it is relatively cheap. With the abundant wind resources of New England, we do not foresee much difficulty in each state meeting its Renewable Portfolio Standards.

In other words, having decided on our suite of input assumptions, we discover that the model consistently chooses to build up renewables on the bottom and reduce capacity on the top, via demand response expansions. There is then a choice between the two primary low-cost options of natural gas and Canadian imports, to fill the gap in the middle. Importantly, both of these technology options have pressing constraints. We believe that there will ultimately be a toss-up between the cost of expanding the region’s pipeline capacity and building new high-voltage DC interconnections with Quebec. Based upon our results, holding carbon and natural gas price projections constant, allowing coal power plants to retirement could speed up the pace of a less carbon-intensive energy mix transformation.

Key uncertainties include the limited capacity of imported hydro transmission lines, the limited capacity of natural gas pipeline and the possible leakage danger of the natural gas pipeline. These uncertainties will have significant impact on the decisions of ISO-NE's energy future. ISO-NE will have to rethink whether to go further to import more hydro from Southern Canada or to build more natural gas pipelines in order to meet increasing electricity demand. In future studies, we recommend taking these uncertainties into consideration, therefore, making our forecasting more accurate and reasonable.

V. CONCLUSION

There are several key points our client can take away from our model results. First of all, it will be important to pay attention to the trends in fuel prices, as fluctuations are likely to occur and can have significant impacts upon the fuel mix since price directly impacts the bottom line for utilities. Trends of the natural gas price and the price of imported electricity from Canada, in particular, could have a strong effect on the energy mix of installed capacity in New England, depending on the magnitude of price changes. If it turns out that natural gas prices do change substantially, then most of the gap between the installed capacity and peak demand through 2025 will likely be filled by new wind and natural gas installations. Accurate projections of the future electric generation supply mix will enable effective planning for future capacity installation.

Annual severe winter weather often stresses New England's electric supply's ability to meet heating needs. New England must either increase its imported hydro from Canada or invest in natural gas pipeline infrastructure in order to maintain reliable service. It has yet to be determined which alternative New England will choose. The ability to ensure reliable, safe and affordable electricity supplies to New England will be influenced by many of the factors we explored in our project. We believe the most important factors to consider are future fuel prices; changes in the Renewable Portfolio Standards; demand response; carbon tax; and the status of the imported hydro contracts between Canada and New England.

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